Microturbine Generator (MTG) Field Test Pgm.

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Prepared By:
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Prepared By:
Electric Power Research Institute (EPRI)
3412 Hillview Avenue
Palo Alto, California 94304
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Prepared For:
California Energy Commission

Gary Klein
Contract Manager

Terry Surles
Program Manager
Public Interest Energy Research Program

Marwan Masri
Deputy Director
Technology Systems Division

Robert L. Therkelsen
Executive Director

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MTG Field Test Program

Interim Results

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Cosponsors:
Public Interest Energy Research Program (PIER)
California Energy Commission
1516 Ninth Street
Sacramento, California 95814

EPRIsolutions
3412 Hillview Avenue
Palo Alto, California 94304

EPRIsolutions Project Manager
W. Steeley

EPRIsolutions • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10414, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com.

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CITATIONS

This report was prepared by

Energy Signature Associates, Inc.
220 Dombey Drive
Pittsburgh, PA 15237

Principal Investigator
R. McClelland

This report was prepared for

EPRIsolutions
3412 Hillview Avenue
Palo Alto, California 94304

and

Public Interest Energy Research Program (PIER)
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

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REPORT SUMMARY

The overall application of microturbine generator (MTG) systems is evolving and ultimately depends on technology implementation by utilities and commercial and industrial customers. To help its members assess MTG technology and its future prospects, EPRI has developed a MTG field test program.

Background

Small recuperated gas turbines in the 30- to 100-kW range, known as microturbines, have recently become available from manufacturers. These generating devices are principally targeted for grid parallel peaking and peak shaving uses, as well as for grid-independent backup power in the event of a grid upset or outage. This market entrance has heightened interest by electric distributors—and their customers—in how well and efficiently such systems operate and in their installation and operation costs.

Objectives

- To ascertain cost, performance, durability, reliability, and maintainability of microturbines in an actual customer environment.
- To note promising types of applications and modes of operation.
- To ascertain any grid interconnection performance issues.
- To assess related prospects for future use.

Approach

Nearly forty microturbine units have been installed at various utility and utility-customer sites. Participants include a wide range of investor-owned electric utilities, municipal electric companies, and rural cooperatives.

Although the bulk of the units are natural gas fueled, either with high-pressure or with low-pressure gas requiring an add-on or add-in fuel compressor, other units within the program complete the applications profile by using propane or fuel oil. While most units are installed at a broad spectrum of climates and electric grids across the United States, others are installed in Canada and overseas. At all of these sites, results are accumulated at varying levels of detail and incorporated into an experience database that is covered in this interim report.

Results

Microturbine operating performances are compared with initial manufacturer specifications and also contrasted between manufacturers and among various field operating modes. Sufficient operating experience also exists to define the fundamental reliability of the turbine-generator-

recuperator combination and the balance of the system, which includes controls, fuel compression, and related peripheral components.

Installation costs are analyzed relative to manufacturer and, thus, as a function of generating size (for example, costs for a 30-kW versus a 75-kW field installation). Although thermal recovery installations are very few, sufficient data is available to define fundamental thermal recovery costs and potential for any meaningful busbar cost reduction impact. Moreover, field installation cost experience also combines with basic microturbine performance to yield estimates of busbar costs for peaking and baseloaded applications under various ownership profiles.

EPRI Perspective

Utilities, energy service providers, and customers planning to use microturbines need to understand how they work before making significant investments. They also need to know how unit operation will affect local electrical distribution grids.

By overcoming many of MTG's technical and economic challenges, EPRI believes that progress is being made to make MTG technology feasible for use by utilities and many commercial and industrial customers. However, there are still significant challenges before technical and cost goals of some products are attained. These goals need to be achieved before MTGs can effectively compete with other distribution system reinforcement alternatives or before customers can use them to reduce their energy costs.

Keywords

Compressor
Efficiency
Heat rate
Inverter
Microturbine

ABSTRACT

Under this demonstration program, more than 40 microturbines in the 30- to 100-kW size have been installed at a broad spectrum of demonstration sites. These units, running in baseloaded and peaking service, have provided valuable field verification of manufacturer specifications and of the actual installation costs involved in making basic, fuel-electric, and thermal recovery installations. The resulting experience has been used to assess the fundamental state of development of the main turbine-generator-recuperator microturbine component and of related peripherals like the inverter, fuel compressor, and equipment-interconnect controls. These results, including installation and thermal recovery costs, are used to assess resulting busbar costs under various operating and ownership profiles.

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1 INTRODUCTION

Technology Background

Microturbine generators have an extensive foundation derived from routinely practiced, existing technology. Microturbines are small gas turbines in the 100 kW range based on: automotive and truck turbochargers, auxiliary power units for aircraft and tanks, and even small jet engines for drone aircraft. Since many of these precursor applications have volume or weight constraints, efficient recuperation transfer of exhaust energy to preheating inlet air preheating is not widely practiced. Thus, these microturbine predecessors tended to have relatively low, gas turbine-type efficiencies.

A number of factors combined in the mid-1990's to enhance interest by manufacturers in developing microturbines as grid power generation devices. These include:

- Continuing state and federal regulations, as well as incentives, to improve energy efficiency by using on-site generation for the concurrent production of heat and power, commonly called CHP or cogeneration.
- Improvements in materials and in computer modeling technology for cost effective aerodynamic and thermodynamic design improvements.
- Increased importance of assured power for computer and manufacturing operations, and
- Growing, but perhaps now diminished in many customer's minds, concerns over electric grid costs, availabilities, and reserve margins, particularly in California.

As a result, a number of manufacturers began efforts to design equipment targeted at "commercial" generation using recuperated microturbines. A typical microturbine generator and its energy balance is shown in Figure 1-1.

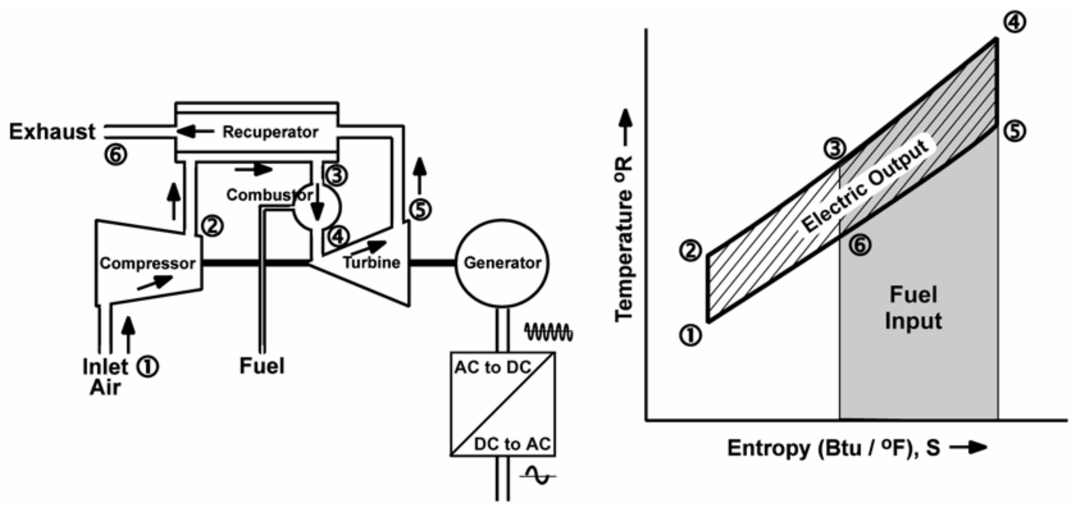


Figure 1-1
Microturbine Generator Functional Diagram

As illustrated in the flow sheet, a microturbine has the same basic components as an ordinary combustion turbine. These turbines work by compressing inlet air ① up to several atmospheres, say 60 to 80 psig, where it exits the compressor ②. The power to provide this compression comes from a common shaft with the expander turbine.

In a normal compression cycle of say ambient air for a 50 psig output, the compression energy will significantly warm the inlet air.For example, at ISO conditions of 59 °F ambient temperature, the compressor exit temperature at ② will be approximately 330 °F; at an 80 psig discharge, 420 °F. This compression requires significant power and can represent as much as two-thirds of the work produced in the expander. Thus, a considerable amount of work is going on inside a microturbine even when it is running at idle and not producing any electric power output to the customer or grid.

In a conventional, simple-cycle combustion turbine, high pressure fuel would be burned at the compressor exhaust. However, in a recuperated microturbine, the compressed air is first heat exchanged with the expander turbine exhaust which might be on the order of 1,200 °F. The net result is that the amount of fuel is significantly reduced. This also explains why the turbine exhaust is on the order of 400 °F to 500 °F since the compressor discharge temperature in effect limits the amount of heat exchange that can be accomplished. This exit exhaust at ⑥ can also not be used to warm the inlet air at ① prior to compression because it takes significantly more energy to compress hot air compared to cool air.

In any event, the combustion products from the recuperated air and fuel then exit through an expansion turbine. This turbine provides the power to run the compressor, with the expander running the generator to convert the “left-over” shaft horsepower into high frequency AC electricity after powering the compressor.

The companion figure on the right is a T-S diagram that explains the turbine cycle’s thermodynamics. The Y-axis is temperature. As with other gas and thermodynamic calculations, this is the absolute temperature in degrees Rankine which is calculated as °R = °F + 460. Likewise, pressures in any such diagram need to be in absolute terms. Absolute pressures are calculated by adding local atmospheric pressure to the pressure that would be read inside the turbine on a local gauge. Thus, $Psia = Psia_{siteevevation} + Psig$ where the normal atmospheric pressure is 14.696 psia at sea level.

The X-axis of the graph is entropy which is essentially the energy left over at any point if the gas were to do useful work such as expanding through a turbine. These units are Btu per °F. Thus, a plot on the T-S Figure shows the inlet air: being compressed, ① to ② and then heated in the recuperator, ② to ③. This hot air is then mixed with fuel and burned in the combustor, ③ to ④; and expanded to recover shaft horsepower in the turbine, ④ to ⑤. This exhaust discharge then exchanges heat with the incoming compressed air ⑤ to ⑥. Since the Y-axis has units of degrees temperature and the X-axis units are Btu per degree temperature, energy inputs are represented by areas. For example, the fuel input Btu's are graphically shown by the shaded area under the curve from ③ to ④ which is the combustion portion. If the recuperator were not used, the fuel input would stretch from ② to ④! Likewise, the cross-hatched area is the energy available to produce electric power in the generator and is the area bounded by ① to ② to ③ to ④ to ⑤ to ⑥ and back to ① which closes the area and cycle. Thus, a T-S diagram provides a good way to understand the energy dynamics of a microturbine and why a microturbine has significantly better efficiency in comparison to an ordinary, unrecuperated gas turbine.

Microturbine Generator Developmental Features

Given the number of peripheral elements of the turbogenerator shown in Figure 1-1, a micro-turbine for grid power generation has a number of potential developmental features needed to convert historic microturbine practice into proven grid and customer electric generation performance. These can potentially include:

- Improved aerodynamic or manufacturing efficiency using enhanced blade and rotor engineering
- Recuperator upgrading, or even new designs, to enhance efficiency and manufacturing potential
- Inlet fuel compressor to increase the pressure of gaseous fuels at near ambient pressures to the 60 to 80 psig that is required to push fuel into the high pressure combustor chamber
- Converter to rectify the generator's high frequency AC into DC and then to convert that DC into 3-phase power of acceptable quality for customer or grid use
- Extension of controls beyond the historically normal start – operating –monitoring – shutdown functions into regions such as remote monitoring, SCADA interfacing, and the like
- Addition of controls to monitor grid parameters and automatically perform reliable electric grid and customer connect – disconnect functions
- Weather proofing the system for outdoor use across a broad range of climatic conditions
- Development of application, installation, commissioning, and service tools and manuals

- Development of designs and manufacturing processes that are consistent with economic application of the technology

Obviously the successful implementation of these and other performance elements is of keen interest to electric grids and their customers and, thus, forms the fundamental foundation of this EPRI demonstration exploration.

EPRI Demonstration Program Goals

As noted above, many vendors are developing microturbine generators targeted for grid and customer use. This demonstration program has a multi-fold purpose:

First, ascertain the performance, durability, reliability, and maintainability of the technology.

Secondly, define promising applications for microturbine generators.

Thirdly, focus on the suitability of key materials, designs, and components for utility and customer performance.

Fourthly, note any issues associated with the interaction of the units with the grid and any related dispatch.

This Interim Report is the first assessment of the program results and the above factors.

Competitive Profile

Absent the 200kW ONSI fuel cell in some high value “green” applications, the chief micro-turbine competitor, other than the grid itself, is most probably the ubiquitous reciprocating engine. Based on industry information, approximately 16 million kW of stationary reciprocating engines are sold annually for stand-by and cogeneration use. The bulk of these are diesel fueled with about 20 percent being natural gas fueled. The portable power market, most of which is gasoline fueled, represents another 14 million kW each year.

A comparison between a 60 kW microturbine and its diesel engine principal competitor is shown on the next page in Table 1-1. Interestingly, for machine in the 60 kW range, the weights are about equal between a microturbine and a packaged diesel generator although the micro-turbine typically occupies twice as much volume at 100 to 200 cubic feet.

The microturbine is generally easier to site because of its lower noise, vibration, and emission concerns relative to a diesel generator. For example, NOx emissions are significantly lower for the microturbine and complex catalytic controls are not required. However, application economics greatly favor the diesel engine which is much lower in initial cost and also somewhat more efficient. One factor which tends to offset at least some portion of the reciprocating engine’s economic advantage is that the engine is somewhat more difficult to maintain because it involves heavier parts immersed in lubricating oil that must be changed relatively often because of contamination from combustion blowby from its combustion cylinders.

Table 1-1
Microturbine and Packaged Diesel Generator Comparison

Feature	Packaged Microturbine	Packaged Diesel or Natural Gas Fueled Generator
Capacity	60 to 75 kW	60 kW
Volume (Cubic Feet)	100 to 200	65
Weight (Pounds)	1,900	2400
Purchase Price	\$60,000 to \$80,000	\$20,000
Maintenance Cost	~1 ¢ per kWh	~1.5 ¢ per kWh
Heat Rate (Btu HHV / kWh)	13,000 to 15,500	11,500
Emissions (NOx ppm) (NOx gm/hp-hr)	<9 0.17 Nat Gas	~350? Diesel: ~2 Nat Gas Catalytic: 1 to 2

In contrast, most of the microturbines use hydrodynamically supported gas bearings, usually called air foils. While more difficult to manufacture, these air foil bearings do not require oil lubricants since a film of "air" rather than oil supports the shaft inside the bearing. The net result, might be a savings of ½ cent per kilowatt-hour in favor of the microturbine. When annualized at a 10 percent cost of capital over a 40,000-hour 5-year life, the resulting maintenance savings would be equivalent to a \$9,100 equivalent first-cost credit to offset at least some portion of the microturbine's initially higher purchase price.

Microturbine Demonstration Program Structure

As will be seen in Figure 1-2 on the next page, this microturbine demonstration program encompasses a broad spectrum of manufacturers and climates. Forty five sites are represented encompassing six manufacturers. Locations range from the frigid winters of Alaska to the sweltering summers of Texas and Florida. Since many of these units are in grid parallel operation, the demonstration also encompass a wide range of grid interconnect conditions. The program also contains a wide range of participants from IOU electric utilities to municipal utilities and nine rural co-operatives. The manufacturers include: Bowman, Capstone, Elliott, Honeywell, Ingersoll-Rand, and Turbec.

The resulting program includes nearly thirty Capstone units, five of which were precommercial Beta units. Most of these Capstones are 30 kW using gas pressures in the 10 to 15 psig level.

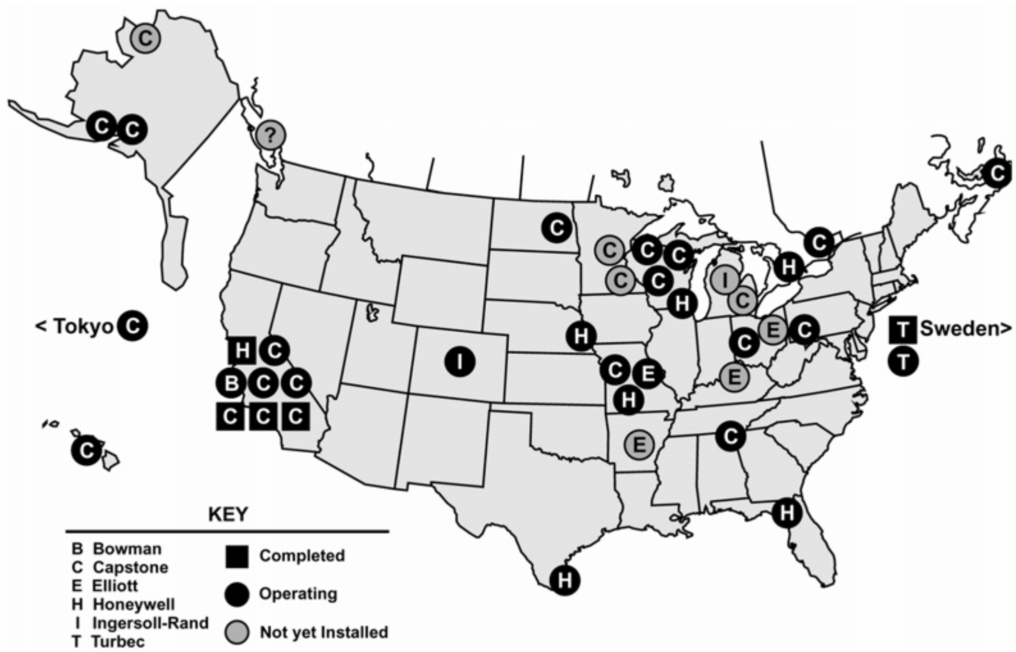


Figure 1-2
Microturbine Generator Demonstration Sites

This level is largely set by the unit's internal rotary fuel compressor. This tends to make the Capstone an outdoor unit since stringent code requirements limit natural gas pressures in occupied spaces to 2 psig. However, two of these units are oil fueled and consideration is being given to demonstrating the recently available 60 kW Capstones in both fuel oil and natural gas service.

In addition, of course, to the fact that these larger Capstones have become recently available, two additional reasons exist for these installations. One is that certain sites had previously selected the 60 kW Capstone and are awaiting delivery. The second reason is that Honeywell has terminated production and withdrawn from the market. This withdrawal has to do with marketing and production economics, rather than with fundamental technical factors as the units worked as well, and as reliably, as the other units in the program. In any event, Honeywell's buyout reimbursement will likely be applied by some of the demonstration participants toward the purchase of 60 kW Capstones, or the 80 kW Elliott units, both of which are now becoming available.

The second largest number of units in the program are the seven Honeywell units, that are now being decommissioned at their request. As described above, some of these may be replaced with Elliotts, the 60 kW Capstones, or perhaps even other manufacturer's units. The balance of the program consists of a handful of Bowman, smaller Elliott, Ingersoll-Rand, and Turbec units.

2
MANUFACTURERS AND DEMONSTRATION EXPERIENCE PROFILES

Introduction

This section of the report profiles the various key microturbine generators embedded in the demonstration program and discusses the resulting overall field experience. As in any demonstration program having multiple units from manufacturers, there will always be a range of user experiences some of which may be more, or less, favorable than others. The attempt here is to cover the bulk of the experience that appears relatively universally applicable.

The outputs and efficiency that are tabulated in the profiles are manufacturer's data corrected for Higher Heating Values (HHV) and based on using relatively low pressure natural gas, in the 0.3 to 2 psig range, as the fuel. Manufacturer's typically rate equipment outputs and efficiencies based on high pressure gas supply and by using Lower Heating Values. Most gas distribution systems typically have, at best, 2 psig available for use at ordinary customer sites. Even if a reworked service line or new meter is added, the normal street pressure might be on the order of 20 to 30 psig even if the gas utility would agree to supply that pressure to the microturbine, which is not an assured conclusion. One reason is stringent code restrictions. Fuel gas compressors for microturbines are universally electric driven and, thus, add parasitic load to the unit as well as black start complexity. Making this parasitic power correction is needed since fuel compression loads typically consume four to six percent of the microturbine's output, and of course, have a like impact on the unit's net electrical output and heat rate.

Also, microturbine manufacturers typically rate their product on a Lower Heating Value (LHV) basis as is commonly practiced in the aerospace and gas turbine industries. LHV's assume that any combustion product water is not condensed and, of course, natural gas is principally methane. Combustion of a molecule of methane produces one molecule of carbon dioxide and two molecules of water vapor, which if condensed would contribute a fair amount of heat to a HHV calorimeter.

Indeed, natural gas is sold on a Higher Heating Value basis. This is because the only way heating values could be historically measured was with a water bath calorimeter, which of course condenses all the water vapor products of combustion. For somewhat the same historic rationale, solid and liquid fuels sold to the utility industry are also reported on a HHV basis. Unfortunately, the difference between heat rate valuations based on HHV and LHV is far from trivial. Natural gas with a LHV of 945 Btu per standard cubic foot might have a HHV of about 1050 Btu per standard cubic foot. Thus, if fuel cost estimates were incorrectly made for a microturbine based on manufacturer's LHV specifications, the annual cost will be eleven percent low since the gas company sells HHV's; not LHV's. For these reasons, the profiled data has been converted to "market" Higher Heating Values. For clarity, such conversions will always have a HHV notation attached to efficiency or heat rate tabulations.

Capstone

Capstone 30 kW unit at Chugach Electric

Output:	**~29 kW, Also now 60 kW**	
Efficiency:	**15,400 HHV Btu/kWh** **…or… 22% HHV** ***Incl low pressure nat gas compressor***	
Size: Footprint	**10 square feet**	
Volume	**64 cubic feet**	
Weight:	**1,100 pounds**	
Cost:		
If 30 kW:	**$39,500**	**→ $1,300 per kW**
If 60 kW:	**$63,500**	**→ $1,050 per kW**

Note: ***Efficiencies and ratings are based on HHV using low pressure natural gas. Costs also include Grid Parallel plus Grid Independent capability with a gas compressor included.***

Figure 2-1
Capstone Microturbine Profile

The Capstone is a well finished unit that can be specified for: natural gas, medium Btu gas, propane, or fuel oil. Capstone units received generally good marks for design implementation and support quality. Most of the unit is designed for "plug and play" maintenance. For example, the inverter is essentially a sealed "box" that can be readily unplugged and swapped out in the field.

The microturbine uses an air bearing turbogenerator incorporating an annular built-in recuperator. Such gas bearings support the shaft on a film of air rather than oil, and are commonly called "foil" bearings. The integrated design enables the hot gas section, including the turbine and recuperator, to be changed out in a two to three hours. Target life for the hot section, which includes the microturbine and annular recuperator, is 40,000 hours between changeouts.

The 96,000 rpm turbine drives a direct coupled generator that interfaces with an inverter to produce 3-phase, 480 volt power for grid or customer use. Because the inverter is a true 4-pole design, substantial current unbalance can be tolerated when running in Grid Independent operation to support customer loads during an electric outage.

The unit requires fuel gas pressures of 55 psig. This microturbine package incorporates an innovative can-type rotary fuel compressor that also functions as a gas pressure regulator.

This compressor, initially using sealed oil-type bearings, is principally designed for gas in the 5 to 15 psig range.Since codes generally limit gas pressures to 2 psig in structures, this inlet fuel requirement largely consigns the unit to outdoor applications. Unfortunately, the initial life of these oil-bearing rotary fuel compressors has typically been limited to around three to five thousand hours at best. Moreover, rebuilt replacements last from a few hundred to a few thousand hours. A gas bearing rotary fuel compressor retrofit kit, costing on the order of $6,000, has now been developed that is capable of accepting gas fuel inlet pressures as low as 0.2 psig. This new design of rotary fuel compressor is expected to have an operating life measured in tens of thousands of hours.

In addition, Capstone had earlier worked with Copeland to develop an external package using an oil-lubricated scroll compressor capable of supplying compressed fuel for up to three 30 kW units or one 60 kW unit. This compressor has an 8,000-hour service interval and costs about the same as the internal foil-type rotary fuel compressor. Although none of these external compressors are currently operating in the demonstration program, one Capstone using this alternate compressor is anticipated to start shortly.

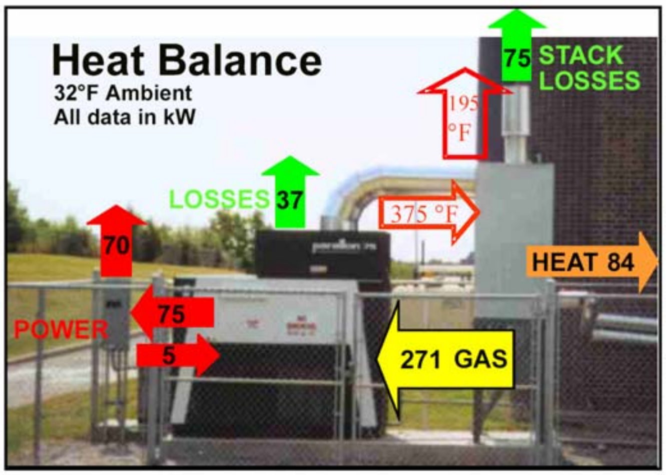
Thermal recovery potential for the 30 kW Capstone is about 190,000 Btu per hour. This would be equivalent to supplying 4.2 gpm of domestic water heating at a 90 °F rise. There are now two suppliers for related thermal recovery equipment, one of which is Unifin. Only a few applications within the demonstration program are using heat recovery. One reason is that the participants' target has principally been to confirm the workability of the microturbine itself as contrasted to demonstrating more longer-term peripheral applications.

Although there is always a mix of experiences in any demonstration program, users have been almost universally impressed with Capstone's service support and related quality, although sometimes issues like modem communications have taken several cycles and some time to work out. Capstone's service training program was particularly well assessed.

Field measurements of NOx output have been under the 9 ppm rating with some measurements as low as 2 to 6 ppm. However, as might be expected, some offspec NOx emissions have been observed during startup. While the units appear to be within noise specifications, an objectionable high frequency tone has been observed at many installations. One site has resorted to sound adsorbing fencing; another, to building a small shed around the unit. Other sites have not noticed any problem. Capstone recently upgraded the sound adsorbing "roof" kit which appears to help significantly. Some units have experienced flameouts at low output levels which appears to have been resolved by a combination of gas pressure and rotary fuel compressor tuning, as well as software upgrades. As with the Honeywell unit, some grid independent installations have experienced battery discharge failures due to questionable design accommodations for battery recharging.

There have been two field failures of turbines, both of which appear due to the inadvertent introduction of liquids into gas fueled turbines. The first was at a high pressure propane fueled unit where the ambient temperatures apparently got low enough to recondense the LPG in the line between the vaporizer and the microturbine. It should be noted that 60 psig propane will recondense at around 30 °F depending on the amount of butane in the mixture. As a result, that fuel supply system was reconfigured inside the unit and a liquid trap added. The second failure was in an atypical natural gas system that has previously known problems with liquid condensates being carried into customer sites. Thus, although a teardown will be needed to potentially confirm the failure cause, it appears that both problems may have been due to atypical site liquids problems. At minimum for any microturbine operating where liquids may exist, care needs to be exercised to make sure that liquids do not enter the gaseous fuel train by prefiltering and liquid traps.

Honeywell



Output:	**~70 kW**
Efficiency:	**13,500 HHV Btu/kWh** **…or… 25% HHV** ***Incl low pressure nat gas compressor***
Size: Footprint	**30 square feet**
Volume	**220 cubic feet**
Weight:	**2,800 pounds**
Cost:	**$57,000 ⟶ $800 per kW**

Note: ***Efficiencies and ratings are based on HHV using low pressure natural gas. Costs also include Grid Parallel plus Grid Independent capability with a gas compressor included.***

Courtesy of the Canadian Distributed Generation Program test site in Toronto, Canada. Thermal recovery shown is Unifin rather than Honeywell's.

Figure 2-2
Honeywell Microturbine Profile

The Honeywell is a relatively well finished unit that can be specified for natural gas, propane, or fuel oil. Honeywell units also received generally good marks for design implementation and for support quality, although in some instances the support commitment was more visible the level of individual field service personnel dedication. Much of the unit is individual component based rather than modules and, thus, has less reliance on "plug and play" major components.
See Figure 2-2.

The microturbine uses an air bearing turbogenerator coupled to a separate recuperator. The unit is somewhat more efficient than the Capstone because its power section operates at a slightly higher pressure. In this instance the site fuel delivery, or internal compressor output, needs to be 75 psig. The 65,000 rpm turbine drives a direct coupled generator that interfaces with an inverter to produce 3-phase, 208 volt power for grid or customer use. However, since most modern sites typically use 480 volt 3-phase power, a separate 2.5-foot square autotransformer option is usually part of the site installation. Target life for the microturbine section is 10,000 hours between changeouts with a 1,200 limitation on starts. The recuperator has a 40,000 hour design life.

The inverter uses a 3-pole design which would not normally present a problem when dispatching to a typically balanced grid. However, when operating Grid Independently, as in the case of standby power to a customer's site, the current flows in the three phases must be matched within about ten percent for the Honeywell unit. While this would be no problem for pure 3-phase motor loads like chillers or coolers, it represents a potentially serious restriction for more universal backup power supply at typical customer sites which impose significant 110 volt single-phase loads on portions of their three phase circuit. While customers might indeed want a microturbine for peak load shaving, these units are expensive enough that the added benefit of fully usable standby or backup power in the event of a grid upset or outage remains an important added-value customer feature that may not be present with this unit.

This Honeywell microturbine package can include an internal electrically-driven compressor to accommodate site pressures down to 0.3 psig. Unlike the innovative Capstone rotary fuel compressor, the Honeywell compressor is based on relatively proven technology and has generally worked well in the field. Of course one option that would probably also work would be to use the Capstone-Copeland compressor, assuming that the compressor controls could be made to talk with a Honeywell microturbine.

Some early units experienced fuel compressor failures and retrofits were issued which appeared to resolve that issue. As with the Honeywell unit, some grid independent installations have experienced battery discharge failures due to questionable design accommodations for battery recharging.

Thermal recovery potential for the 70 kW Honeywell is about 350,000 Btu per hour. This would be equivalent to supplying 7.8 gpm of domestic water heating at a 90 °F rise. Honeywell has its own thermal recovery package and similar alternative equipment is available from Unifin as evidenced in the above site application photo. Only a few applications within the demonstration program are using heat recovery.

Honeywell has recently terminated all effort in their microturbine. The business was deemed unviable due to a coupling of low sales with high manufacturing cost. High natural gas prices were an additional factor. It should also be noted that Honeywell's marketing strategy, unlike the other manufacturers, was to sell product exclusively to corporate entities offering third-party energy services in exclusively licensed territories. While that strategy embedded corporate purchase commitments to reduce market entry volume concerns, the marketing concept carried with it the risk that such proxy purchasers might not develop such an energy service market with committed vigor. Honeywell is now engaging in a "refund" program requiring mandatory decommissioning and it is far from assured this technology base will be purchased and reconstituted by any other party.

Elliott

The Elliott machine now being prepared for demonstration testing is an outgrowth of the 45 kW partially recuperated microturbine presently operating at a few locations. Several of these new 80 kW units are prospectively planned for demonstration within this program's umbrella. This includes two units already planned for demonstration and perhaps some additional units as replacements for Honeywell units being decommissioned. These units can be presently specified for natural gas, with other potential fuels including propane or fuel oil.

The microturbine uses an oil bearing turbogenerator coupled to a separate Elliott recuperator. The unit is somewhat more efficient than the Capstone unit since the power section operates at a higher pressure. In this instance the site fuel delivery, or internal compressor output, needs to be 80 psig. The 115,000 rpm turbine drives a direct coupled generator that interfaces with an inverter to produce power for grid or customer use. A minor overhaul is targeted at 27,000 hours with a major overhaul at 54,000 hours. See Figure 2-3.

The inverter is a 4-pole design producing 480 volt, 3-phase power which should make it suitable for both Grid Parallel and Grid Independent uses. This Bowman-manufactured inverter is largely “stick built” and probably offers less opportunity for “plug and play” field service. Manufacturer service on the one present 45 kW unit is now rated as good. The present enclosure requires some type of rain shielding for outdoor use. Because of its other product lines, Elliott has a quite useful distribution and service structure already in place.

Courtesy of Elliott. Inverter is not shown.

Output:	**~76 kW**
Efficiency:	**13,500 HHV Btu/kWh** **...or... 25% HHV** ***Incl low pressure nat gas compressor***
Size: Footprint **Volume**	**25 square feet** **95 cubic feet**
Weight:	**1,900 pounds**
Cost:	**$75,000 → $1000 per kW**

Note: ***Efficiencies and ratings are based on HHV using low pressure natural gas. Costs also include Grid Parallel plus Grid Independent capability with a gas compressor included.***

Figure 2-3
Elliott Microturbine Profile

Ingersoll-Rand

The Ingersoll-Rand machine now entering very limited demonstration testing is a Beta unit operating in small numbers. One is just now being commissioned and, thus, limited information is available.

The microturbine uses an oil bearing turbogenerator coupled with a separate recuperator. This high-speed, oil lubricated microturbine, including a power wheel for combustion air compression, is aerodynamically coupled with a second independent 44,000 rpm power wheel and gear assembly driving a standard 3,600 rpm induction generator. Because the separate power wheel allows more aerodynamic design and speed flexibility, the I-R unit is potentially superior in efficiency. A major overhaul is conceptually planned at 80,000 hours. See Figure 2-4.

The use of an induction generator to generate 480 volt 3-phase power simplifies grid interconnect. However, this also constrains the machine to operate only in a Grid Parallel mode, such as for peak shaving at a customer's site. A synchronous generator, capable of Grid Independent operation in the event of a grid upset or outage, is prospectively planned at some point in the future.

Courtesy of IR Energy Systems.

Output:	**~68 kW** ***(estimated)***
Efficiency:	**11,600 HHV Btu/kWh** **…or… 29% HHV** ***Incl low pressure nat gas compressor***
Size: Footprint	**15 square feet**
Volume	**110 cubic feet**
Weight:	**3,000 pounds**
Cost:	**~$80,000 → $1200 per kW**

Note: ***Efficiencies and ratings are based on HHV using low pressure natural gas. Costs include only Grid Parallel capability but do include a gas compressor.***

Figure 2-4
Ingersoll-Rand Microturbine Profile

To provide the 80 psig fuel gas pressure required for the unit, an electric drive, oil flooded screw compressor can be included with the machine. Thermal recovery is already built-into the unit and would be the equivalent of 7.5+ gpm of domestic hot water heating at a 90 °F rise.

The cabinet is presently designed for utility or boiler room use. Thus, as has already become apparent within the unit's demonstration program installation, a surrounding enclosure of some type is required for an "outdoor" installation.

Although the unit clearly promises efficiency advantages if performance matches expectations, no field data is currently available to confirm that efficiency advantage. Even if the unit offers improved efficiency, the lack of an outdoor enclosure coupled with an induction generator allowing only Grid Parallel, non-backup power use will likely constrain market attractiveness.

Because of its other product lines, Ingersoll-Rand has a quite useful distribution and service structure already in place.

Bowman

There are two European manufacturers represented in the program, one of which is Bowman. While two alpha units have also been tested, the most recent and commercially germane, is the TG80 model. This indoor unit includes built-in thermal recovery and has a footprint of 29 square feet. Bowman, which does not manufacture the turbo component, does supply its own recuperator and shares much in common with the Elliott unit where Bowman is providing the inverter module section of the unit. The program's Bowman unit has run for over 2000 hours with an average heat rate of 14,200 Btu on a HHV basis at a 74 kW net output. Because of the importance of thermal recovery in much of the European market, the unit has a capability for some degree of thermal load following. Due to the current potential cross-supply of key components between Bowman and Elliott, the prognosis for commercial success of either unit may well be interlinked.

Turbec

The demonstration data is from an indoor beta unit operating in Sweden. That unit, which has now been shutdown, produced about 22 kW at ISO conditions at a 16,500 Btu HHV heat rate. However, this heat rate did include a 10 percent transformer loss. This unit included built-in thermal recovery that typically produced 29 kW equivalent of usable thermal output. Based on that experience, Turbec is now releasing a T100 unit projected by the manufacturer to produce 100 kW of net 400-volt electrical output at a 12,500 Btu HHV heat rate. This indoor unit, whose performance is currently untested in this demonstration program, would also include built-in thermal recovery and have a footprint of 27 square feet.

3 INSTALLATION COSTS

Demonstration Installation Costs

As part of the demonstration program, participants have been requested to tabulate the actual installation costs for the microturbine unit. Embedded in the requested cost outline are such items as:

- Engineering and installation design
- Permitting
- Site preparation such as concrete work and fencing, if needed
- Fuel supply interconnect including meters and piping, and including storage tanks where needed for an oil or propane fueled units
- Electrical output interconnect including wiring and metering, disconnect switches, transfer switches where necessary, customer load segregation when needed, and the like
- If installed, thermal recovery and related interconnects including heat exchangers, pumps, piping and controls
- Instrumentation and data collection that were added because of the demonstration nature of the site

Some of the participants selected a sites or installation components beyond the scope of a typical mature market installation and others may have added additional metering and instrumentation. Thus, participants were also asked to project what the microturbine installation costs would have been for a "normal commercial" installation.

While some demonstration sites are still developing these cost reports, a number of others have provided the related installation cost spreadsheet reports. These results are shown in Figure 3-1 on the next page. Because fuel oil sites are likely to require a more complex fuel interface, those are categorized separately from natural gas and propane installations.

During any microturbine installation, thermal recovery is essentially an overlay on top of a site having fuel and electrical interfaces. Thus, thermal recovery expenditures have been separated and analyzed separately. Thermal recovery information from the two applicable sites are reported at the bottom of the figure.

Demonstration sites were individually reviewed to determine the application category. As evidenced by the top bars and as reported by the participants, certain installations had site or cost components that were not typical of a normal commercial installation. Examples were excessive interconnect distances or demonstration-related metering or controls. In these instances, participants usually reported both the actual installation cost and included a parallel accompanying estimate as to what the installation costs would have been for a more normal, non-demonstration installation. These types of demonstration sites are shown by the dual shading in the bars. The darker bar shows the "commercial" estimate and the lighter extension reports the extra cost associated with the atypical portion of that demonstration site's selection or installation. An example of this type of reporting is the Capstone 1 installation. In contrast, other demonstration sites already proxied, or were located, at a normal commercial site. These sites are shown by the single dark bars, of which, one example being the Capstone 4 site.

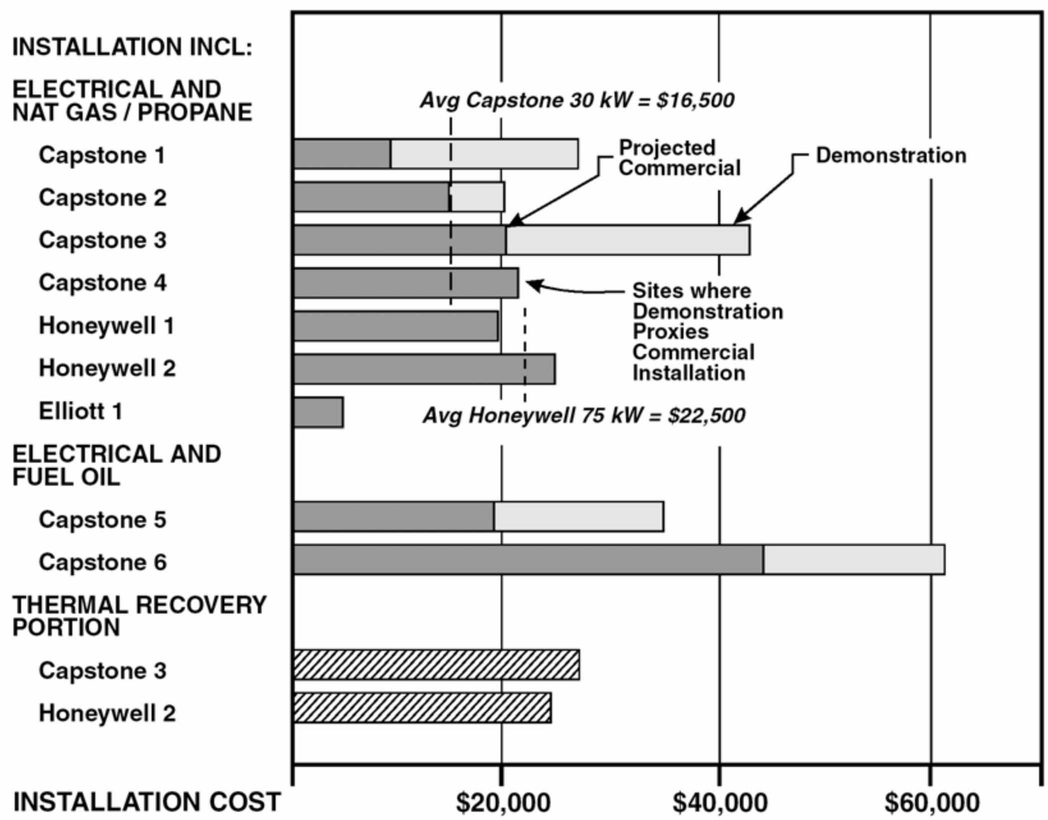


Figure 3-1
Installation Cost Reports

For natural gas or propane sites, the average cost projected for the 30 kW Capstone installations is $16,500 or $550 per kW. Although the data is very limited, the two Honeywell 75 kW sites have an average installation cost of $22,500 which works out to $300 per kW.As evidenced by the graph, the installation cost data is limited and the results show significant variation within the installation estimates, particularly for the oil fueled installations.

None the less, these results are interestingly provocative in that they show little difference the total cost for installing a 30 and a 75 kilowatt microturbine at a commercial customer's site. This is somewhat to be expected since much of the installation costs are labor, and the materials costs are not likely to change significantly between the two related fuel piping and wiring sizes. As could be anticipated, the results clearly suggest that dominant factors influencing site installation costs are very much site specific. For example, long or difficult fuel and electric interconnects will likely drive up the total installation cost much more than whether or not the microturbine is a 30, 60, or 75 kW unit.

Thermal Recovery Cost and Benefits

As described earlier, thermal recovery costs were isolated from normal electrical and fuel installation costs. The resulting thermal recovery cost at the two applicable sites are $27,000 and $24,000 respectively. Because of the site complexity typically existing in thermal recovery design and installation, the relative closeness of this data is far more likely to be statistical happenstance than engineering certainty. Nonetheless, data provides useful guidance to assess the economic practicality of thermal recovery.

Thermal recovery potentials for the Capstone 30 kW unit and for the Honeywell 75 kW unit are respectively 6,300 Btu/kW/Hour and 4,700 Btu/kW/Hour. Using an average representative value of 5,500 Btu/kW/Hour, the economic value of thermal recovery can be calculated at various energy costs and sources as shown in Figure 3-2. The results are plotted for $5 and $10 per million Btu natural gas and for 5-cent and 10-cent per kWh electricity. The calculations use a projected percentage of thermal energy recovery from microturbine exhaust for use as space heating or water heating. In the case of natural gas, the recovered energy is corrected for an 80 percent conversion efficiency in the replaced application. Electric replacement uses a 100 percent end user efficiency.

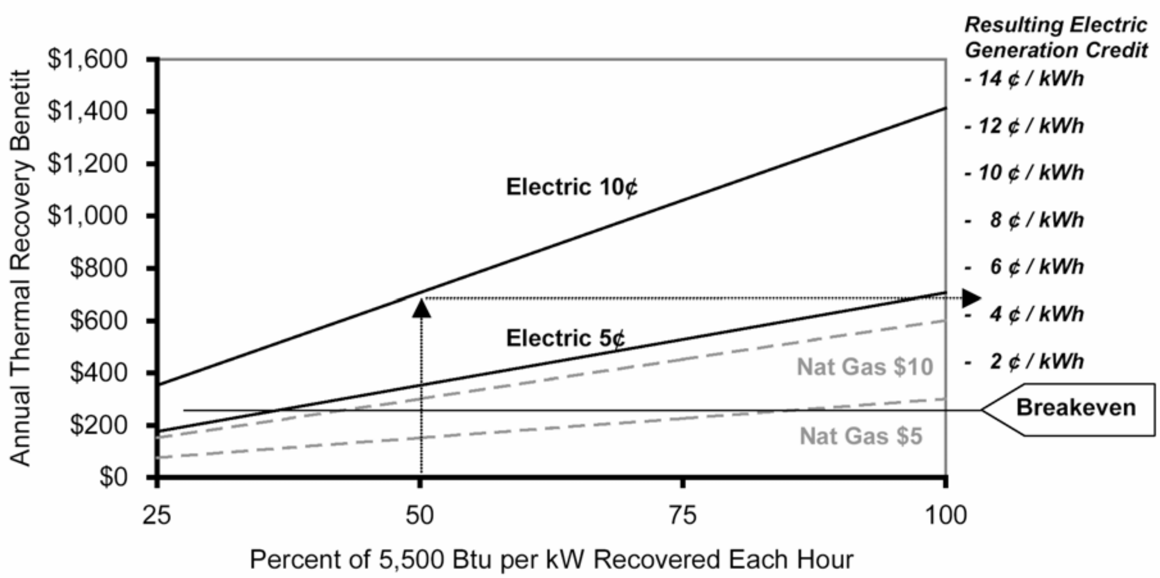


Figure 3-2
Thermal Recovery Benefit Analysis

Installation Costs

Using the thermal recovery costs from the "Capstone 3" entry in Figure 3-1, the expenditure to secure thermal recovery benefits will be $27,000 divided by 30 kW or $900 per kW of microturbine electrical capacity. If this commercial customer has a cost of capital of 15 percent before taxes and needs to amortize the related thermal recovery investment within five years, the annual equivalent cost can be determined. The resulting capital recovery factor for the investment would be $[(1 + i)^n] / [(1 + i)^n - 1]$ *where $i = 0.15$ and $n=5$* yielding an annual rate of 0.2983. Thus, the annual customer cost associated with the thermal recovery would be $900 times 0.2983 or $268 dollars per year. This is shown as the breakeven line on Figure 3-2.

The remaining thermal savings after the breakeven investment repayment can then be used to offset the cost of electricity from the microturbine. For example, if 50 percent of the thermal energy could be recovered to displace an electric water heating load at 10¢ per kWh, the overall savings would be $706 per year less a deduction of $268 annually that recovers the $900 per kW initial thermal recovery installation. The resulting annual savings due to thermal recovery would be $706 minus $268 which equals $438 per year. This residual can be credited against the microturbine's power production cost. If the unit were baseloaded and ran every hour of the 8,760 hours in the year, then the Resulting Electric Generation credit would be $438 ÷ 8760 or 5.0 cents per generated kilowatt hour.

Figure 3-2 suggests that thermal recovery will probably not be economically practical for fuel prices around $5 per million Btu as it will not make sense to displace other gas uses by microturbine thermal recovery. The residual savings are simply to small after the initial investment is recovered. However, as gas prices increase, thermal recovery to displace other gas uses may start to make sense provided that more than one-half the thermal energy can be utilized and that the customer intends to install the microturbine anyway for peaking savings or for assured backup power. In contrast to the price sensitivity for natural gas, displacement of almost any electrically heated load becomes relatively attractive even if the displaced electric cost is only 5¢ per kWh. If electric prices reach the 10¢ level, almost any thermal recovery can be attractive and the savings can reach very significant levels if extensive thermal recovery can be achieved. However, the potentials for large savings from high electric costs for water heating are somewhat illusionary since 10¢ power would be equivalent to $29 per million Btu gas and it is very unlikely that a customer would consciously choose such costs if natural gas at the $5 to $10 level were available for thermal uses.

Moreover, it should be noted that attractive thermal recovery uses having large, steady loads are nearly impossible to find in normal commercial applications like office buildings and shopping centers. However, thermal recovery should certainly be explored for selective applications with large, stable thermal uses such as hospitals, laundries, food processing, certain types of industrial applications, etc. Thermal recovery should also be explored for any site which is using any meaningful amount of electric water heating or where other electric loads exist that that could be replaced by hot water exchanger temperatures in the 190 °F range, uncommon as such applications may be.

Motor Start Capability

Microturbines use inverters to convert DC power from the high frequency generator and rectifier assembly into 60 cycle, three-phase power used by site loads or the electric grid. Inverters typically use high frequency switching and pulse width modulation wave form generation. However, the related switching transistors, like all solid state components, are low in mass and catastrophically sensitive to thermal overloads caused by excessive throughput currents.

Motor starting capabilities of inverters associated with microturbines can be an important site criteria, making or breaking a particular customer application. However, most of the microturbines in the demonstration program are typically operating in grid parallel. Obviously when the microturbine is connected in parallel with the grid, the grid is a large sink and can readily supply the starting currents. However, if the unit is operating in a Grid Independent mode, then motor starting loads are a far different and more serious matter.

As motors come up rapidly to their rated speed, a large amount of current is drawn as the shaft accelerates to speed. The momentary inrush current for the first one-half cycle to start the motor shaft rotating can be 1000% of the normal running current. Then to bring the motor up to its synchronous speed, the accelerating current, called the Locked Rotor Current, can be as much as 7.5 times the running current or power for as long as 40 to 60 cycles or about 3/4 of a second! This situation is even worse with many new motors. A high efficiency motor can have inrush currents as high as 1800% of the running current and acceleration, Locked Rotor Currents, as high as 1000% of the running current, albeit over a slightly shorter starting time.

Moreover, this starting current for a load is influenced by actual type and level of load that the motor is driving. Some motors for store-sized compressors also have dual windings for softer starting. In many instances, it may be virtually impossible to define the starting current of a site application motor from its load and nameplate without actually measuring the starting loads and then comparing those with the microturbine manufacturer's specifications.

For example, one microturbine manufacturer rates the 480 normal maximum current to be 46 amps. With a balanced load at a 1.0 power factor, the normal current into a three-phase, 480-volt load would be 35 amps for a machine having a net output of 29 kW. In contrast the starting current limitation is 54 amps for a maximum of 10 seconds. Thus, the effective motor starting current rating is 54/35 yielding a head room of 54% over the steady state run rating. Under these circumstances and given a start current equal to 875 percent of sunning current, the unit could start a 6.8 HP motor or a 6 Ton heat pump if that were the only load on the unit. However, if the inverter in the microturbine was already supplying 75 percent of its rated capacity to preexisting loads, the maximum loads that could be started would be either 3.5 HP or 3.1 Tons.

These kinds of limits could pose serious constraints on the use of microturbines as backup power during grid outages, and thereby derate what is likely a key customer benefit and selling feature. Fortunately, however, torque-limiting soft starters for motor add-ons are now entering the market. These small sized, easily installable soft starters are cost effective in the $300 to $400 range. If torque is limited to 25 percent, and thus starting current to 50 percent of the earlier numbers, the resulting motor start capabilities would be 13.7 and 7 HP for the same 30 kW class microturbine. Thus, motor starting capabilities may not now be as serious a marketing limiting factor as might have been anticipated when microturbines first entered the market.

4
OPERATING EFFICIENCY

Microturbines are particularly sensitive to ambient temperature as well as other factors like altitude. At cooler ambient temperatures, less power is required for the combustion air compressor and, as a result, the heat rate improves. This is shown Figure 4-1 for two different manufacturers. The changes are relative to ISO conditions which are 59 °F and Sea Level. The differences in the two manufacturer curves also reflect factors other than basic turbine operating thermodynamics. These can include such elements as design approaches relative to controlling combustion temperatures, limitations on current from the high speed generator as power output increases, and a number of other factors.

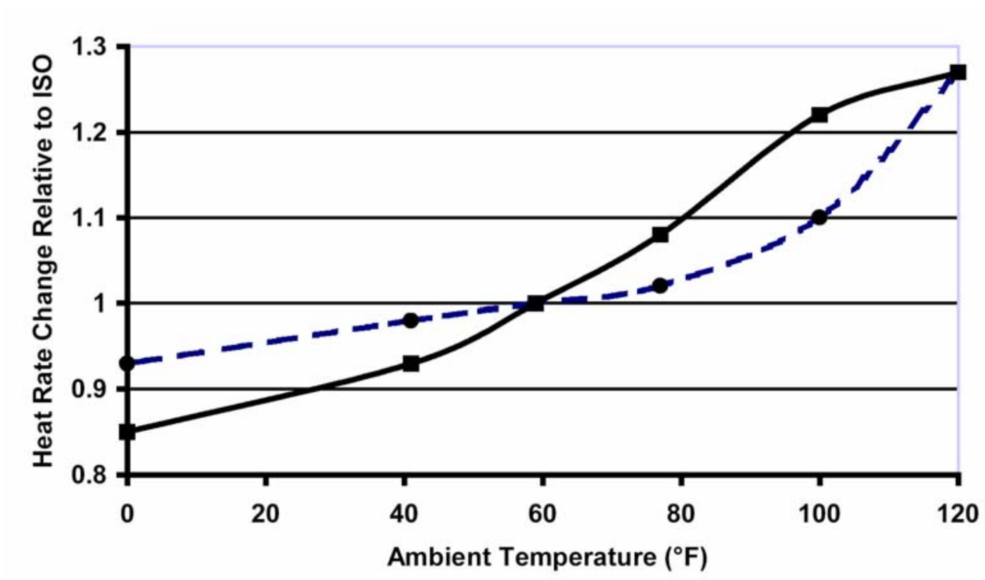


Figure 4-1
Microturbine Heat Rate as a Function of Ambient Temperature

The dominant portion of the demonstration's data arises from monthly meter readings and the resulting tabulations or graphs of monthly heat rates. One such example is Figure 4-2 on the next page which shows monthly demonstration performance of a 30 kW Capstone running on 10 to 15 psig natural gas from the local utility. Up until the last month, the unit was demonstrating base loaded operation with an efficiency reasonably consistent with the manufacturer's information. However, as part of the demonstration protocol, the microturbine operation has been changed to simulate two periods of peaking dispatch each day. As is evident form the chart, the micro-turbine's heat rate deteriorated by almost 16 percent during the "peaking" simulation. Such changes, and the lack of site data to make temperature corrections, illustrate much of the difficulty associated with using limited raw field data to validate manufacturer unit specifications.

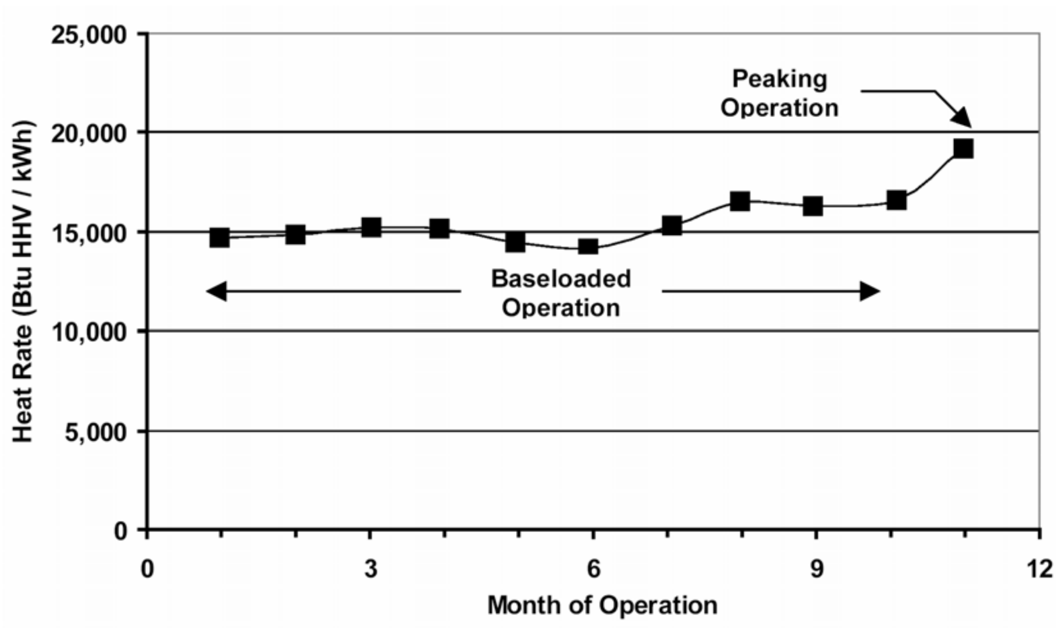


Figure 4-2
Microturbine Heat Rate versus Month of Operation

One way around this difficulty is to "find" site data for conditions close to, or at, the basic ISO specification conditions of 59 °F. Another alternate is to look for sites in regions or operating months where the operating conditions are likely to be at, or above, the ISO temperature. If the heat rates under these conditions were to be in the range of the manufacturer's ISO specification, then a reasonable presumption would be that the machines were likely performing relatively well. These type of results are shown in Figure 4-3 for various sites in the demonstration program. For reference purposes, the specific heat rate is concurrently shown for the Capstone at ISO conditions based on units requiring gas compression. The Honeywell expected heat rate would be around 13,500 Btu per kWh. As the bar chart shows, the Capstone units appear to be running in the manufacturer's specification range. This is also at least anecdotally shown by the graph in Figure 4.2. However, the graph's prospective tendency for the Capstone heat rate to deteriorate under peaking dispatch conditions does raise a prospective issue meriting further review as more field data becomes available.

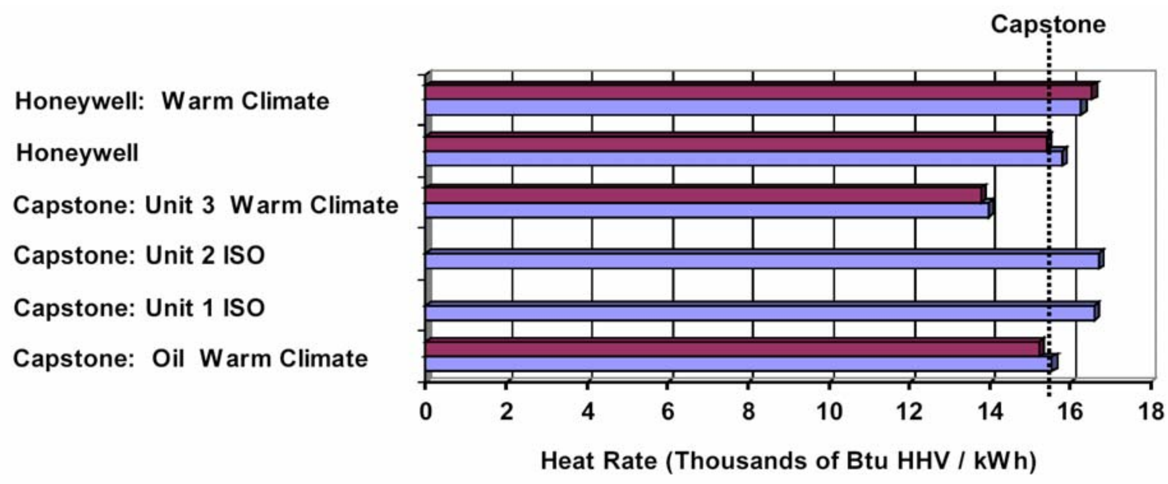


Figure 4-3
Microturbine Heat Rate at Various Sites

Beyond question, much of the demonstration data from the bulk of the field sites merits further analytical and statistical investigation as additional results and more detailed reporting become available. Even so, one result of the demonstration has been to already confirm that microturbines can operate reasonably close to specification, at least insofar as sufficient Capstone data exists.

5
MICROTURBINE ECONOMICS

Even with the preliminary reporting that is now available, an important result has been sufficient reporting and operational experience to project application costs for utility and customer owners. These costs are reported in Table 5-1 for various application modes and customer types. The two broad application types include peaking or peak shaving use for 1,500 hours a year and full base loaded service. In order to provide an analysis of fuel cost sensitivity, the units are assumed to be natural gas fueled at $5 and $10 HHV per million Btu. The higher of the costs is also useful in that it can be used as a proxy for alternate fuels. For example, $10 natural gas would be equivalent to 91 cent per gallon propane and $1.35 per gallon fuel oil. Because of the way the calculations work, the user can readily interpolate between, or extrapolate beyond, the $5 and $10 prices to arrive at the results for any other fuel cost.

Table 5-1
Cost of Microturbine Application

Operating Profile and Fuel Cost	Cost to Customer (Cents / kWh)		
	Rural Co-op	IOU Electric	Customer Owned
Peaking @ 1,500 Hours per Year:			
Natural Gas = $ 5 per Million Btu HHV	22.9	29.9	33.2 to 42.8
$10 per Million Btu HHV	29.9	36.0	40.3 to 49.9
BaseLoad @ 95% avail = 8,322 Hours per Year:			
Natural Gas = $ 5 per Million Btu HHV	11.2	12.3	13.0 to 14.8
$10 per Million Btu HHV	18.3	19.4	20.1 to 21.9

Basis: Excludes cogeneration credit which at full thermal recovery might reduce busbar costs 1 and 4 ¢/kWh for gas prices of $5.00 and $10.00 per MilBtu respectively.
$1,100 / kW equipment plus $275 / kW installation *10-Year equipment life*
14,200 HHV Btu / kWh heat rate *Maintenance at 1.5 cents per kWhr*
Debt is at 9% were applicable *Utility ROE is 15%*
Customer Owned ROE is 25% *3.3 Year Payback w w/o debt financing*
7-Year MACRS where applicable *No Investment Tax Credit*
Combined FIT + StateIncomeTax rate is 41.5%

The table shows that peaking, or for that matter peak shaving, costs for a microturbine can range from 23 to 50 cents per kWh and that the range for baseloaded operation is 11 to 22 cents per kWh. The range depends on fuel cost and for customer owned facilities on whether or not the customer has debt financing as part of the ownership package.

The initial investment in the microturbine is based on a $1,100 purchase cost per kW plus installation costs of $275 dollars per kW. This is reasonably consistent with present microturbine offerings in the 60 to 75 kW size range. No thermal recovery is included in the investment or operating savings based on the assumption that any related energy savings would more or less be required by the installation to pay off the extra investment required to install that thermal recovery.

Co-ops are assumed to assess the investment as a 100% debt financed project. In contrast, investor owned utilities and customers are assumed to evaluate the purchase as a mix of debt and a equity. Equity returns are calculated as a true after-tax discounted cash flow return with a tax rate of 41.5% for a combination of federal and state taxes. Target returns for investor utilities are 15%; for customers, 25%. The range for customer costs reflects whether or not the customer mixes some debt in with the investment financing. The higher customer value is, of course, due to all equity financing by the customer. The customer return target of 25% is equivalent to a 3.3 year payback requirement.

As indicated by the calculated busbar costs, most customers and owners are not likely to consider a microturbine an attractive generation device in its own economic right. In other words: at the present pricing, customers are not likely to consider a microturbine as a very attractively priced source of electric power except in very high cost electric regions. However, if the customer needs backup power to avoid the risk or expense of grid outages …or… has unusually attractive thermal uses …or… has siting constraints relative to a diesel engine, the use of a microturbine could well become attractive. One result of the demonstration program has been to confirm that microturbines do have the potential for sufficient reliability and operability and, thus, make the source for “other compensating benefits to pay for it” at least a reasonably viable consideration.

6 CONCLUSIONS

The EPRI microturbine demonstration program encompasses a broad spectrum of manufacturers and climates. Forty five sites are represented encompassing six manufacturers. The manufacturers include: Bowman, Capstone, Elliott, Honeywell, Ingersoll-Rand, and Turbec. Since many of these units are in grid parallel operation, the demonstration covers a wide range of grid interconnect conditions and includes a wide range of participants from IOU electric utilities to municipal utilities and nine rural co-operatives.

This demonstration program is to ascertain the performance, durability, reliability, and maintainability of microturbine technology. And secondly, to note promising applications for microturbine generators and if electrical interaction problems existed with the grid. This interconnect concern does not appear in this report because there were no interconnect issues to report.

The resulting program includes nearly thirty Capstone units, five of which were precommercial Beta units. The second largest number of units in the program are the seven Honeywell units, that are now being decommissioned. Honeywell's withdrawal from the market has to do with marketing, present fuel prices, and production economics, rather than with fundamental technical factors since the units worked as well, and as reliably, as the other units in the program. The balance of the program consists of a handful of Bowman, smaller Elliott, Ingersoll-Rand, and Turbec units.

As in any demonstration program having multiple units from manufacturers, there will always be a certain range of user experiences some of which may be more, or less, favorable than others. The attempt in this report is to draw conclusions from the bulk of the experience that appears relatively universally applicable. Users have been almost universally impressed with Capstone's service support and related quality, although sometimes issues such as fuel compressors and the like have taken several cycles and some time to work out. Capstone's service training program was particularly well assessed. The Honeywell is a relatively well finished unit that can, like the Capstone, be specified for natural gas, propane, or fuel oil. Honeywell units concurrently received generally good marks for design implementation and for support quality.

Demonstration participants usually reported both the actual installation cost and included a parallel accompanying estimate as to what the installation costs would have been for a more normal, non-demonstration installation. For natural gas or propane sites, the average cost projected for the 30 kW Capstone installations is $16,500 or $550 per kW. Although the data is very limited, the two Honeywell 75 kW sites have an average installation cost of $22,500 which works out to $300 per kW.

Conclusions

Thermal recovery costs were isolated from normal electrical and fuel installation costs. The resulting thermal recovery cost at the two applicable sites are $27,000 and $24,000 respectively. Because of the site complexity typically existing in thermal recovery design and installation, the relative closeness of this data is far more likely to be statistical happenstance than engineering certainty. Nonetheless, data provided useful guidance to assess the economic practicality of thermal recovery.

Thermal recovery will probably not be economically practical for fuel prices around $5 per million Btu. However, as gas prices increase, thermal recovery to displace other gas uses may start to make sense provided that more than one-half the thermal energy can be utilized and that the customer intends to install the microturbine anyway for peaking savings or for assured backup power.

Motor starting capabilities of inverters associated with microturbines can be an important site criteria, making or breaking a particular customer application. However, most of the microturbines in the demonstration program are typically operating in grid parallel. Obviously when the microturbine is connected in parallel with the grid, the grid is a large sink and can readily supply the starting currents. However, if the unit is operating in a Grid Independent mode, then motor starting loads are a far different and more serious matter.

Based on estimates from data developed in this demonstration, peaking costs for a microturbine can range from 23 to 50 cents per kWh. The range for baseloaded operation is from 11 to 22 cents per kWh. The range is based on a $5 to $10 per million Btu fuel cost and for customer owned facilities on whether or not the customer has debt financing as part of the ownership package. These values are based on a $1,100 purchase cost per kW plus installation costs of $275 dollars per kW. This is reasonably consistent with present microturbine offerings in the 60 to 75 kW size range. No thermal recovery is included in the investment or operating savings since any energy savings would more or less be required by the installation to pay off the extra investment required to install that thermal recovery.

As typified by these busbar costs, most customers and owners are not likely to consider a microturbine an attractive generation device in its own economic right. In other words: at the present pricing, customers are not likely to consider a microturbine as a very attractively priced source of electric power except in very high cost electric regions. However, if the customer needs backup power to avoid the risk or expense of grid outages …or… has unusually attractive thermal uses …or… has siting constraints relative to a diesel engine, the use of a microturbine could well become attractive. The key result of the demonstration program has been to confirm that microturbines do have the potential for sufficient reliability and operability and, thus, make the source for “other compensating benefits to pay for it” at least a reasonably viable consideration by customers and utilities.